U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20460

August 8, 2023

RE: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units and Repeal of the Affordable Clean Energy Rule (Docket EPA–HQ–OAR–2023–0072)

Energy Innovation appreciates the opportunity to submit these comments to the U.S. Environmental Protection Agency (EPA) regarding its *Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units* (proposed rule). Energy Innovation is a nonpartisan energy and environmental policy think tank, providing research and original analysis to help policymakers and regulators make informed choices on energy policy. Our team has expertise in modeling pathways to affordably and reliably decarbonize the U.S. electricity grid and in power system regulation at the state and federal levels. We are submitting these comments to help inform the decision-making surrounding the proposed rule and to share relevant findings from recent techno-economic analyses, engineering best practices, and real-world case studies.

In particular, we focus these comments on the reliability of the U.S. power system under the EPA's proposed rule limiting emissions from coal-fired power plants, with some additional comments on the proposed rule limiting emissions on existing gas units in Appendix 1. We offer evidence that reliability should not and very likely will not be undermined by the EPA's proposed rule, which would require coal-fired power plants that do not make an enforceable commitment to retire by 2040 to reduce their CO_2 emissions rate by nearly 90 percent, and place limits on emissions from existing gas-fired power plants greater than 300 megawatts in size and operating at a capacity factor greater than 50 percent.

We also note that the last time the EPA finalized a rule meaningfully limiting greenhouse gas (GHG) emissions from existing power plants—the Clean Power Plan—numerous stakeholders protested on reliability grounds. The same can be said for many other rules surrounding conventional air pollution from power plants. However, the power sector achieved the Clean Power Plan's 2030 goal by 2020 without degrading reliability, even though the rule never entered force. Numerous stakeholders are poised to do the same for this proposed rule.

However, the EPA once again has granted utilities and system operators ample time to make plans and let markets work to phase out unabated coal in time to comply with the rule. As these comments will show, affordable, mature technologies are available today to enable a full transition away from unabated coal power by 2035 or sooner, and utilities of all kinds and sizes were already planning to do so. Furthermore, as explained in Appendix 1, limits on emissions from existing gas units are unlikely to undermine system reliability for similar reasons.

Our comments are structured into three sections making three distinct, complementary arguments:

1. The EPA's proposed rule will not undermine resource adequacy in the U.S. grid, because coal-fired power plants are not necessary for resource adequacy.
2. The EPA's proposed rule will not undermine real-time operational reliability because there are ample ways to replace the essential reliability services provided by coal plants.

3. Existing utility plans to phase out coal by 2035 or sooner demonstrate that the EPA's proposed rule will not undermine grid reliability.

We are also confident that maintaining proposed emissions limits for existing natural gas-fired EGUs would not undermine grid reliability for similar reasons, as explained more fully in Appendix 1.

While these comments focus on rules for existing coal-fired power plants and the proposed rules as they stand, there may be room to strengthen emissions standards. The existing fleet of power plants, new renewables, storage, and low-carbon fuels can likely meet the grid's reliability needs under the proposed rule or even stronger emissions standards. There is growing consensus among utilities, analysts, engineers, regulators, and other stakeholders that we can rapidly transition to an electric system dominated by wind, solar, and other clean energy resources, due to recent and anticipated technological advances, durable federal support, and cost declines. As with the Clean Power Plan, the EPA and many utilities likely underestimate the rate at which technology, new business models, and policy will transform our power system.

Section 1: The EPA's proposed rule will not undermine resource adequacy in the U.S. grid, because coal-fired power plants are not necessary for resource adequacy

In this section, we discuss six studies that model the retirement of all or nearly all coal-fired power generation in the U.S. or a region within the U.S. Even though the EPA predicts minimal impacts on the power system from the proposed rule, the proposed rule sets standards requiring coal plants that operate in 2040 and beyond to install CCS by 2030, which some stakeholders may argue will undermine the U.S. grid's ability to provide adequate power to meet growing demand. The rule also provides less stringent standards for those coal units that retire before 2040. The EPA's baseline may either over- or under-predict the impacts of the Inflation Reduction Act (IRA), necessitating a look at how other studies predict the future evolution of the U.S. power system and solve for EPA's predicted rule impacts. In total, the six studies use four modeling tools to reach the same conclusion as the EPA—the U.S. electricity system feasibly could and likely would remain resource adequate even if all unabated coal generation retired by 2035.

The EPA's Regulatory Impact Analysis (RIA) forecasts that the proposed Clean Air Act section 111(d) rule will lead to no unabated coal-fired power capacity by 2035. To make this forecast, the EPA relies on the Integrated Planning Model (IPM), one of several industry-standard power sector modeling tools. The EPA's forecasted rule impact represents a slight acceleration in coal retirement beyond the business-as-usual case, which predicts that all but 30 GW of coal retires even without the rule by 2035—a roughly 85 percent fall from 2021 levels. The EPA finds this capacity would be supplemented by 12 GW of coal capacity with CCS in 2035 under the rule.[1] The EPA released a technical support document laying out its resource adequacy analysis, finding "the implementation of these rules can be achieved without undermining resource adequacy."[2]

[1] "Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (U.S. Environmental Protection Agency, May 2023), tbl 3-14. https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

[2] "Resource Adequacy Analysis Technical Support Document" (U.S. Environmental Protection Agency, May 2023), 3, https://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf.

Three large U.S. regions have already demonstrated that it is possible to operate a power system reliably with no or very low amounts of coal, including New York,[3] New England,[4] and California,[5] lending credence to the idea that grid operators can manage reliable systems without coal. However, the RIA results still raise the question of whether the U.S. could retire all *remaining* coal power plants across the country without adversely impacting resource adequacy.

To examine this question, we reviewed six industry-standard studies that retire all remaining coal power plants in the U.S. or within a region of the U.S. grid by 2035 or sooner. Collectively, the studies examine whether and how U.S. electricity systems with no coal-fired generation and much higher penetrations of renewable and other carbon-free electricity can produce adequate energy to meet growing demand. In industry parlance, this is referred to as "resource adequacy." The studies cover a range of institutions, geographies, models, and timelines; they also differ in assumptions around carbon capture, load growth, and policy drivers. All six find their coal-free systems to be resource adequate, with some studies taking a more rigorous approach to reliability modeling than the EPA, including testing their systems' hourly operations over many sample days, weather-years, or stress conditions.

Table 1 summarizes the six studies' results as they compare to the EPA's RIA.

Table 1. Summary – studies map six pathways to resource adequacy without unabated coal by 2035 or sooner

Category	Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions …	Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035	Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System	Net Zero America – Potential Pathways, Infrastructure, and Impacts	The 2035 Report 2.0 – Plummeting Costs and Dramatic Improve-ments in Batteries Can Accelerate Our Clean Transportation Future	Reliably Reaching California's Clean Electricity Targets – Stress Testing Accelerated 2030 Clean Portfolios	Cleaner, Faster, Cheaper – Impacts of the Inflation Reduction Act and a Blueprint for Rapid Decarbon-ization in the PJM Inter-connection
Institution(s)	EPA	National Renewable Energy Laboratory	National Renewable Energy Laboratory	Princeton University	University of California, Berkeley; GridLab; Energy Innovation	Telos Energy; GridLab; Energy Innovation	Princeton University
Release date	May 2023	2022	March 2023	October 2021	April 2021	May 2022	December 2022
Geographic scope	Lower 48 states	Lower 48 states	Lower 48 states	Lower 48 states	Lower 48 states	Western Inter-connection	PJM Inter-connection

[3] Will Wade, "New York's Last Coal-Fired Power Plant to Retire Tuesday," *Bloomberg*, March 30, 2020, https://www.bloomberg.com/news/articles/2020-03-30/new-york-s-last-coal-fired-power-plant-will-shut-down-tuesday.

[4] Scott Merrill and Jill Patel, "How New England's Last Coal-Fired Power Plant Has Managed to Survive," *Concord Monitor*, January 7, 2023, https://www.concordmonitor.com/Understanding-the-longevity-of-Merrimack-Station-49449084.

[5] "California State Profile and Energy Estimates," U.S. Energy Information Administration, April 20, 2023. https://www.eia.gov/state/analysis.php?sid=CA.

Model(s)	IPM	ReEDS	ReEDS	Energy-PATHWAYS & RIO	ReEDS & PLEXOS	ReEDS & PLEXOS	GenX
Study purpose	Assess proposed § 111 rules' impact on the U.S. power sector	Assess scenarios achieving 100% clean electricity by 2035	Assess potential impacts of the IRA and Infrastructure Investment and Jobs Act through 2030	Assess pathways to reach a net-zero economy by 2050	Assess impacts and feasibility of high transportation electrification and 90% clean electricity by 2035	Stress-test reliability in California and the West assuming California meets 85% clean electricity by 2030	Assess impacts of IRA on PJM system through 2035 + assess how other policies can cut PJM GHGs 80-90% by 2035 (vs. 2005 levels)
All unabated coal retires by	2035 (proposed rule case)	2035	2030[6] ("IRA-BIL Mid." Case)	2030 (all scenarios)	2030	2030 ("WECC Coal Retirement" sensitivity)	2030 ("IRA and Cap-and-Trade" case)
CCS built	12 GW coal with CCS, 9 GW natural gas with CCS by 2035	None for coal; very small (but present) for gas and biomass in some cases	Fossil CCS makes up 1-8% of total electricity by 2030	None for coal; ~5% of total electricity for gas and biomass by 2035	None	None	None for coal; up to 14% of total electricity for gas in "IRA and Cap-and-Trade" case
Non-hydro renewable mix[7]	29% by 2030; 46% by 2035	60-80% wind and solar by 2035	40-62% wind and solar by 2030	>50% wind and solar by 2030 in 4 of 5 cases	72% wind and solar by 2035	75% renewable by 2030 (California)	34% renewable in 2030; 52% renewable in 2035
Clean mix[8]	52% clean by 2030; 67% clean by 2035	100% clean by 2035	71-90% clean by 2030	70-85% clean by 2030	90% clean by 2035	85% clean by 2030 (California)	66% clean in 2030; 78% clean in 2035
Load growth	~5% load growth from 2022-2030; ~11% load growth from 2022-2035	66% higher load in 2035 vs. reference case	Up to ~8% load growth from 2023-2030	~10-22% load growth from 2020-2030	~40% load growth from 2020-2035	15% higher load in 2030 in High Electrification case vs. base case	38% load growth from 2021-2035 (and 41% higher peak demand)

[6] Coal generation does not fall to zero in this report but drops to negligible margins in the "IRA-BIL Mid." case by 2030.

[7] Generally defined as wind (onshore and offshore), solar (front-of-the-meter), geothermal, and biomass.

[8] Generally defined as "renewable" plus large hydropower and nuclear power. Only includes CCS if net emissions are zero (e.g., paired with other actions like direct air capture).

Reliability modeling	Capacity expansion modeling subject to resource adequacy requirements	Capacity expansion modeling subject to resource adequacy requirements	Capacity expansion modeling subject to resource adequacy requirements	Simulated hourly operations for 41 sample days + assessed long-term operations through 2050	Simulated hourly operations over 7 weather-years	Simulated hourly operations for 8 weather-years + tested 3 resource portfolios against 7 stressors	Capacity expansion modeling subject to resource adequacy requirements

The 2022 National Renewable Energy Laboratory study, "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035," assesses four pathways to achieve a fully clean U.S. electricity system by 2035 while meeting an electrification target that results in demand growing 66 percent above 2020 levels.[9] The study scenarios include the retirement of all unabated coal-fired power plants by 2035, with 60 to 80 percent of electricity supplied by wind and solar resources, much of the remainder satisfied by hydro and nuclear power, and a marginal amount stemming from natural gas and biomass with CCS. Two pathways also include larger roles for clean hydrogen or new nuclear in the supply mix, respectively. The study finds these electricity systems will be able to meet demand and planning reserve margins during the most constrained hours of the year, even under significant demand growth. However, the ambition of the pace of this transition far outpaces EPA's forecast of the proposed rule impacts.

The 2023 National Renewable Energy Laboratory study, "Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System," analyzes the impact of the IRA and Infrastructure Investment and Jobs Act on the U.S. power system through 2030.[10] The study finds these policies will contribute to the retirement of nearly all unabated coal generation by 2030, suggesting nearly all of the coal-fired generation fleet is likely to be uneconomic to continue operating before emissions reduction requirements from the proposed rule take effect.[11] The study also finds renewables would supply 40 to 62 percent of electricity while clean energy would supply 71 to 90 percent of electricity, with the remainder coming from existing unabated natural gas generation operating at lower capacity factors alongside fossil fuels with CCS. The study finds the system will be able to meet demand and planning reserve margins during the most constrained hours of the year, even under significant demand growth.

The 2021 Princeton study, "Net Zero America—Potential Pathways, Infrastructure, and Impacts," is a thorough, peer-reviewed academic assessment of five potential pathways to achieve a net-zero carbon U.S. economy by 2050.[12] The study finds each pathway would retire all unabated coal power plants by 2030, with wind and solar supplying upwards of 50 percent of electricity in four of five cases and clean energy supplying 70 to 85 percent of electricity across all pathways. The study finds these systems would be resource adequate based on testing hourly system operations over 41 sample days. Some study scenarios

[9] Paul Denholm et al., "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035" (National Renewable Energy Laboratory, August 30, 2022), https://doi.org/10.2172/1885591.

[10] Daniel Steinberg et al., "Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System" (National Renewable Energy Laboratory, March 15, 2023), https://doi.org/10.2172/1962552.

[11] The study also includes a "constrained" case that restricts the amount of renewable energy, transmission, and carbon dioxide pipeline and storage infrastructure that the model is allowed to deploy. This case still sees much of the existing coal fleet retire, but much more coal remains on the system relative to the "Mid" case, suggesting EPA rules could help force these units to reduce their GHG emissions or retire.

[12] Eric Larson et al., "Net Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report" (Princeton University, October 2021), https://netzeroamerica.princeton.edu/the-report.

explore the need for bioenergy with CCS to help drive negative emissions that offset hard-to-decarbonize sectors and reduce the need to build large amounts of renewable energy.

The University of California, Berkeley, GridLab, and Energy Innovation study, "The 2035 Report 2.0," examines a least-cost pathway to reach a 90 percent clean electricity system by 2035 while meeting ambitious transportation electrification targets.[13] The study's main policy scenario retires all coal power plants by 2030, builds no CCS projects across all fossil power plants, and includes a high degree of load growth at 40 percent above 2020 levels. The study finds that the system—with much higher penetrations of renewables than the EPA anticipates—would be resource adequate, based on testing hourly operations over seven weather-years. Notably, the study includes more than 300 GW of battery storage to complement renewable resources, without driving up wholesale electricity costs.

The Telos Energy study, "Reliably Reaching California's Clean Electricity Targets—Stress Testing Accelerated 2030 Clean Portfolios," limits its geographic scope to the Western Interconnection but examines reliability more thoroughly than the other studies discussed here.[14] It tests three potential 2030 California electricity systems achieving 85 percent clean electricity (including 75 percent renewable electricity) against a range of different stressors, including a scenario in which the rest of the West retires all of its coal generation. While California is already a "coal-free" grid, California relies on other Western states for imports, and it sits within a highly interdependent Western Interconnection that still includes significant amounts of unabated coal that will be affected by the EPA rule. The analysis further tests California grid resilience against known stressors such as import limitations, low hydropower availability, faster-than-expected in-state natural gas power plant retirements, and extreme heat. The study finds the systems to be resource adequate in all hours of seven weather-years, including across the range of stress conditions.

The 2022 Princeton study, "Cleaner, Faster, Cheaper—Impacts of the Inflation Reduction Act and a Blueprint for Rapid Decarbonization in the PJM Interconnection," limits its geographic scope to the PJM power market, assessing the impact of the IRA and other potential policies on this coal-heavy region.[15] The study finds that the IRA paired with a market-wide GHG cap-and-trade policy would eliminate coal power by 2030, resulting in a system that includes 34 percent renewable electricity and 66 percent clean electricity by 2030. The study finds the system would be able to meet demand while retaining adequate capacity reserve margins in each hour.

While the EPA's RIA forecasts the elimination of all unabated coal by 2035, it does not forecast that the proposed coal rule will materially impact nuclear, hydro, and non-hydro renewable energy generation relative to the baseline scenario. Instead, EPA modeling predicts the rule will shift power generation away from unabated coal toward more coal paired with CCS as well as unabated natural gas and gas co-fired with hydrogen. This results in a system with 46 percent renewable electricity and 67 percent clean electricity by 2035, with 12 GW of coal with CCS still available.

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[13] Amol Phadke et al., "2035 The Report: Transportation - Plummeting Costs and Dramatic Improvements in Batteries Can Accelerate Our Clean Transportation Future" (University of California, Berkeley; GridLab; Energy Innovation, May 2020), http://www.2035report.com/transportation/wp-content/uploads/2020/05/2035Report2.0-1.pdf.

[14] Derek Stenclik, Michael Welch, and Priya Sreedharan, "Reliably Reaching California's Clean Electricity Targets: Stress Testing Accelerated 2030 Clean Portfolios" (GridLab; Telos Energy; Energy Innovation, May 2022), https://gridlab.org/wp-content/uploads/2022/05/GridLab_California-2030-Study-Technical-Report-5-9-22-Update1.pdf.

[15] Qingyu Xu et al., "Cleaner, Faster, Cheaper: Impacts of the Inflation Reduction Act and a Blueprint for Rapid Decarbonization in the PJM Interconnection" (Princeton University, December 12, 2022), https://doi.org/10.5281/zenodo.7429042.

In aggregate, the studies presented here show that resource adequacy is both feasible and likely even if the U.S. electricity grid transitions even faster than the EPA anticipates will happen in both its baseline and proposed rule scenarios. Analyses by the National Renewable Energy Laboratory and Princeton, for example, anticipate that the IRA will usher in coal retirements and accelerate wind and solar deployment faster than either of the EPA's scenarios. The variation in scope should also increase confidence—studies focusing on the West and PJM confirm these results in specific regions. As noted above, the EPA's use of the IPM represents just one modeling tool, and other industry-standard tools confirm the EPA's assessment that a grid with no unabated coal generation can and will remain resource adequate if clean resources are permitted to replace them at a pace consistent with the EPA's analysis.

Adequacy also requires building replacement resources fast enough to compensate for retiring resources, which has been facing increased headwinds in recent years but should not be a barrier to resource adequacy under these proposed rules. Transmission interconnection and transmission capacity are currently barriers to rapid renewable deployment, as are policies and lack of coordination between regional and state regulators and utilities, as other commenters will certainly note. However, the pace of transition contemplated by the six studies examined here greatly exceeds what EPA forecasts will be necessary to comply with the rule.

The average utility-scale wind and solar additions in 2020-2022 was 25 GW, along with 2 GW of battery storage, according to EIA data. EPA forecasts that under this proposed rule, annual wind and solar additions would be about 20 GW from 2023-2028, and 40 GW between 2028-2040. EPA's forecast represents an modest upward adjustment in pace to maintain resource adequacy that would likely not stress the overburdened interconnection process or slowly expanding regional transmission grid. Furthermore, the falling cost of renewables and storage coupled with sustained policy support from the IRA will likely help overcome those barriers, leading to faster renewables deployment over time. If renewables cannot come online as fast as these studies predict, or even at the slower pace that the EPA forecasts, the proposed rule still allows other resources including new peaking gas turbines, storage, and CCS retrofits that can economically fill the resource adequacy gap while complying with the standard, leaving many options for grid operators and utilities.

The EPA forecasts its rule will result in a system with less renewable and clean electricity, less load growth, and more coal CCS capacity than the systems examined in each of the six studies highlighted above. In aggregate, modeling by the EPA and the studies using different industry-standard models all found that their cleaner electricity mixes meet resource adequacy needs across a wide range of weather conditions and geographic scopes, bolstering the EPA's finding that its proposed rule will not threaten resource adequacy.

Section 2: The EPA's proposed rule will not undermine real-time operational reliability because there are ample ways to replace the essential reliability services provided by coal plants

In addition to resource adequacy, a critical component of the reliability of our electricity system is system stability during real-time grid operation. Power systems need to maintain constant frequency and resources to stabilize voltage during both normal operation and unexpected events.

Reliability authorities and power system operators have identified several essential reliability services (ERS) that help achieve stability. ERS come from a combination of transmission infrastructure, power plants including coal-fired plants, and demand-side resources. Because the EPA projects there will be no unabated coal-fired generation by 2035 under its proposed rule, one of the concerns of grid operators, utilities, and customers will be whether stable, reliable operations can be maintained without these resources. To maintain grid reliability, the essential services coal plants provide will need to be replaced by new or other existing grid assets.

Fortunately, there are several other types of generators and other grid assets that are projected to continue operating under the proposed rule that can provide the same or a better level of ERS compared to coal-fired power plants. These include coal-fired power plants with CCS, new natural gas-fired generation that complies with EPA rules, nuclear power plants, hydro power plants, renewable energy power plants including wind and solar, demand-response, and battery storage. In addition, more than 10 years of technological innovation by 2035 will produce additional technologies to help provide the ERS that coal currently provides. For example, grid-forming inverter technology has been used for decades in microgrids and on small islands, and recent advances are making possible the use of multiple grid-forming inverter-based resources (IBRs) in larger grids to support reliable system operation where there are high shares of IBRs and retirements of conventional generation.[16] Therefore, there are ample resources available today to help maintain and enhance system stability through a transition away from unabated coal, with more resources coming in the near future.

Furthermore, grid regulators are actively working and are vested with adequate authority to ensure continued operational reliability. The North American Electric Reliability Corporation (NERC) is the federally sanctioned reliability organization for the U.S., and helps monitor ERS while conducting research to ensure that resources contribute what's needed to maintain reliability. NERC has been convening various working groups to address IBRs and their capabilities for many years. NERC's efforts began with the Essential Reliability Services Working Group in 2014;[17] this group has evolved into the Inverter Based Resources Working Group, made up of industry experts from North America. NERC's work with this group led to NERC guidelines on grid services and IBRs like wind, solar, and battery storage.[18] In 2022, the Federal Energy Regulatory Commission (FERC) opened a docket for rulemaking for IBRs and solicited industry comments.[19] The resulting FERC Order 2023 specified how IBRs would provide grid services.[20]

As the industry adapts to the increasing levels of IBRs on the grid and the retirement of fossil resources, it has become clear that concerns about the ability to maintain system reliability—in particular grid reliability services—are somewhat misplaced. The capability of IBRs to supply these services has been demonstrated, and has been shown to surpass the performance of traditional resources.

Essential reliability services

The ERS required to maintain grid stability include disturbance ride-through, inertia, reactive power and voltage support, fast frequency response, primary frequency response, automatic generation control, and

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[16] Julia Matevosyan, "A Unique Window of Opportunity: Capturing the Reliability Benefits of Grid-Forming Batteries" (Energy Systems Integration Group, March 2023), https://www.esig.energy/wp-content/uploads/2023/03/ESIG-GFM-batteries-brief-2023.pdf.

[17] See generally Essential Reliability Services Working Group (ERSWG) website: https://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

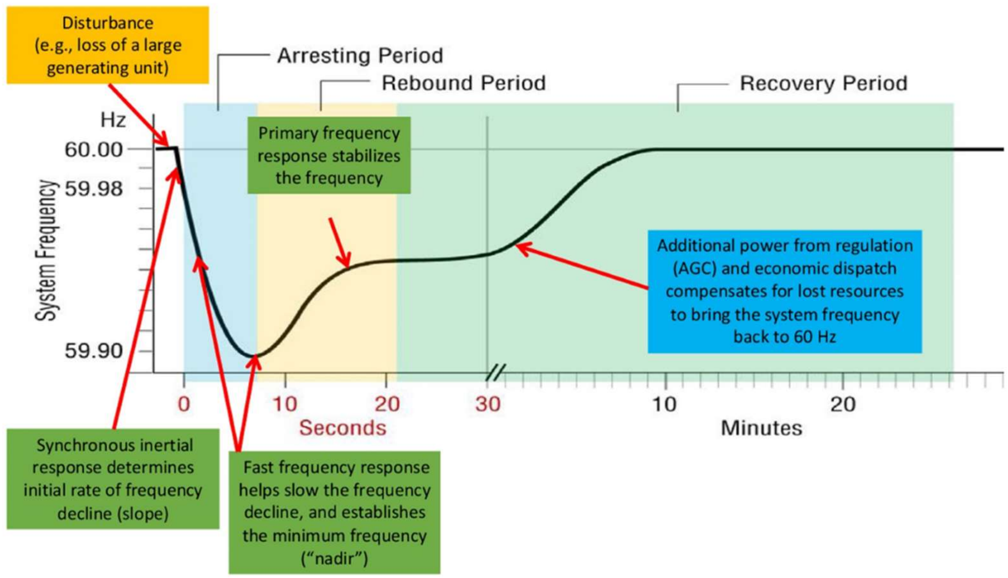
[18] See generally https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx.

[19] "Reliability Standards to Address Inverter-Based Resources, Proposed Rule," Docket No.

[20] FERC, "Order 2023 - Improvements to Generator Interconnection Procedures and Agreements," Pub. L. No. RM22-14–000, 184 FERC ¶ 61,054 (2023), https://www.ferc.gov/media/e-1-order-2023-rm22-14-000.

dispatch/flexibility.[21] These services work along different timescales to stabilize frequency at 60 Hertz, and to control voltage and ensure contingency events do not destabilize the voltage of the bulk electricity system, causing cascading outages. Figure 1 illustrates how ERS combine in a contingency event to restore the frequency of the bulk electricity system.

Figure 1. An example of how ERS stabilize frequency over the course of a grid disturbance and recovery[22]



The following is a list of the ERS defined in Milligan (2018):[23]

- *Disturbance ride-through*: A grid disturbance occurs when a transmission line or generator unexpectedly goes offline, causing the voltage to vary. Typically, this disturbance does not threaten the stability of the grid on its own, but if other generators go offline as a result of voltage swings, cascading outages can occur. Many generators are therefore designed to continue operating if voltage fluctuates within a certain window.
- *Inertia*: Inertia is the stabilizing property of the grid historically provided by large, heavy spinning turbines that resist changes to frequency. Inertia keeps frequency from dropping too quickly when a grid disturbance occurs.
- *Reactive power and voltage support*: Reactive power and voltage control is the reliability service that can help maintain voltage within the proper range and return voltage to its normal operating level after an initial disturbance has occurred, or if voltage is fluctuating significantly during normal operation. To keep voltage within its nominal range and perform this service, generators or other resources can inject more or less reactive power into the grid to lower or raise voltage.
- *Fast frequency response*: After a contingency event, frequency begins to drop at a rate determined by the inertia in the system, as seen in Figure 1. However, inertia cannot stop frequency decline on its own. Fast frequency response is the reliability service that can both slow frequency decline and stop it and is central to the "arrest phase."

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[21] Michael Milligan, "Sources of Grid Reliability Services," *The Electricity Journal* 31, no. 9 (November 1, 2018): 1–7, https://www.sciencedirect.com/science/article/pii/S104061901830215X.

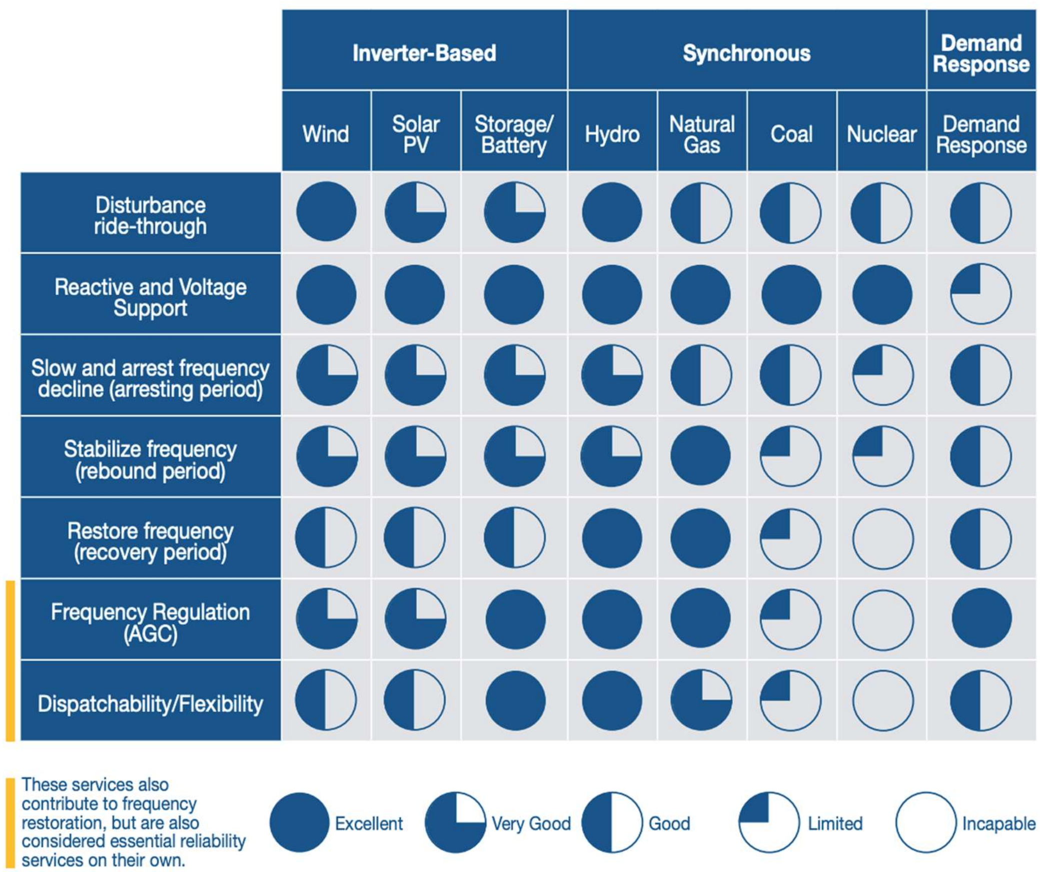
[22] Milligan, "Sources of Grid Reliability Services," Figure 2.

[23] Milligan, "Sources of Grid Reliability Services."

- *Primary frequency response*: Once frequency has stopped dropping, frequency stabilization occurs in the "rebound phase" that begins to bring frequency back to its normal operating level. This reliability service is called primary frequency response, and it is an automatic response to dropping frequency that occurs within several seconds of a disturbance by increasing power output.
- *Frequency regulation*: Frequency regulation is a part of the minutes-long frequency "restoration phase," and a reliability service all on its own. To regulate frequency, generators respond to computer signals at periodic intervals of several seconds to maintain frequency within its nominal range. This is also called automatic generation control, and it is slower than both fast and primary frequency response.
- *Dispatchability/flexibility*: Dispatchability or flexibility refers to a resource's ability to respond to both expected and unexpected changes in generation or load. Often, this means a resource's ability to ramp output up or down over a short timeframe.

New and existing resources can provide superior ERS compared to coal-fired power plants

Figure 2. ERS provided by different grid assets



Source: Milligan, "Sources of Grid Reliability Services."

As seen in Figure 2, coal-fired power plants provide dependable reactive power and voltage support. They also perform well during initial disturbances by continuing to operate when voltage changes and provide inertia to slow frequency decline due to the large spinning mass of their turbine generators. However, coal-fired power plants provide only limited value for many other ERS, including frequency stabilization and frequency restoration. This is largely due to their relative inflexibility—they are not built to quickly change output and have a high minimum run level.[24]

The EPA's proposed rule allows for continued use of coal-fired power plant infrastructure to provide ERS, in at least two ways. First, the EPA contemplates that coal plants can and will be retrofitted with CCS to comply with the standard. Coal plants can also be retrofitted to serve as synchronous condensers, wherein the generators are disconnected from the coal boiler and steam turbine and instead are powered by the grid to spin and provide inertia, reactive power, and voltage support, without generating electricity or burning fuel onsite.[25] In other words, all ERS of a coal-fired power plant need not be lost due to projected decrease in coal-fired electricity.

Regardless of whether coal plants are operated as synchronous condensers to continue providing grid services, new resources that are IBRs will have the capability of providing these grid services. Provided that thermal plant retirements are compensated for by new IBRs, the overall supply of grid services can be maintained with proper planning during the transition.[26]

First, the proposed rule contemplates continued operation as well as new construction of natural gas-fired power plants under several circumstances. In particular, it places few limits on new gas-fired peakers, which are highly flexible and operate at low capacity factors. Newer combustion turbine peaker plants are designed to ramp up and down very quickly, which means they provide good, very good, or excellent grid services across all ERS categories identified in Figure 2. However, because they run infrequently, they would not be providing system inertia most of the time.

The proposed rule also does not regulate hydro power plants or nuclear power plants, which are able to ride through disturbances, and provide reactive power and voltage support services at levels similar to coal plants. Hydro power plants provide very strong frequency support, and both hydro and nuclear plants provide significant system inertia.

Finally, the proposed rule also does not regulate inverter-based clean energy resources that can provide all ERS at levels that support reliable grid operation, when the proper power electronics and controlling software are used. Renewable resources such as wind and solar energy, along with battery storage, are connected to the grid via electrical inverters, which convert the DC power at the resource to the AC grid. These inverters are highly programmable and customizable, resulting in devices that can provide ERS. These inverters are able to ride through disturbances, as is now required by NERC.[27] They can also provide even faster frequency responses than synchronous generators, which means that while they do not provide as much inertia, less inertia is needed to maintain stability when wind and solar are available to increase output.[28] IBRs, especially wind turbines, can also provide "synthetic inertia" to the grid, by programming the inverters to respond to changes in frequency similar to a spinning mass such that they increase power

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[24] The minimum run level represents the minimum level of power output that the resource can reliably produce; a resource with a higher min-gen level is less flexible than a resource with a low min-gen level.

[25] Peter Fairley, "Zombie Coal Plants Reanimated to Stabilize the Grid," *IEEE Spectrum*, July 24, 2015, https://spectrum.ieee.org/zombie-coal-plants-reanimated-to-stabilize-the-grid.

[26] Another prerequisite for reliability is that rules governing the deployment of IBRs allow or require them to provide grid services. This prerequisite has largely been met by a combination of NERC's working groups and the FERC rulemaking described above.

[27] "Industry Recommendation: Inverter-Based Resource Performance Issues" (North American Electric Reliability Corporation, March 14, 2023), https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf.

[28] Paul Denholm et al., "Inertia and the Power Grid: A Guide Without the Spin" (National Renewable Energy Laboratory, May 1, 2020), https://www.nrel.gov/docs/fy20osti/73856.pdf.

output in response to a frequency decrease.[29] Battery storage, which is both dispatchable and inverter-based, also provides excellent ERS.[30]

The EPA has considered the important role of ERS and has designed the rule to allow utilities and system operators the flexibility they need to maintain and enhance reliable grid operations under the proposed rule. Ensuring ERS through the energy transition is not a new topic, and NERC—which is ultimately designated with this responsibility—has already done substantial work on this topic, setting performance-based requirements for these grid services.[31] Regional transmission organizations (RTOs) recognize that markets may need to be developed to ensure new and existing resources are adequately compensated and incented to provide ERS embedded in the existing coal fleet, meaning that utilities, RTOs, and NERC likely have more work to do to map out an orderly transition.[32] But NERC continues to succeed at this mandate, and with the suite of resources available under the proposed rule, there is every reason to believe that continued grid stability is highly likely and eminently achievable.

Section 3: Existing utility plans to phase out coal by 2035 or sooner demonstrate that the EPA's section 111(d) rules for coal-fired power plants will not undermine grid reliability

Grid operators and utilities have already demonstrated that coal-fired electricity generation is not necessary to reliably operate an electricity grid. According to Energy Information Administration (EIA) Form 930 data, many balancing area regions of the U.S. grid generated less than 0.5 percent of total electricity generation using coal in 2022. Balancing areas are responsible for balancing electricity demand, generation, and interchanges with neighboring regions while meeting operating requirements set by NERC. Coal-free balancing areas are managed by large independent system operators such as the California Independent System Operator, New York Independent System Operator, and ISO New England; large vertically integrated utilities such as Florida Power and Light; and federal power agencies like Bonneville Power Agency.[33] Together, these regions accounted for 15 percent of net electricity generation in the U.S. in 2022.

Not only are large portions of the U.S. electricity grid operated without the use of coal today, but many more are planning to end coal use by 2035 or sooner. As detailed below, 25 large coal-owning utilities, which together serve 19 percent of U.S. electricity demand, have plans to be coal-free by 2035 or sooner. These plans cover more than 40 GW of coal—21 percent of currently operating coal capacity—which as of April 2023 stood at 192 GW.[34] These utility plans demonstrate that while some entities affected by this rule

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[29] Peter Fairley, "Can Synthetic Inertia from Wind Power Stabilize Grids?," *IEEE Spectrum*, November 7, 2016, https://spectrum.ieee.org/can-synthetic-inertia-stabilize-power-grids.

[30] See generally Julia Matevosyan, "A Unique Window of Opportunity: Capturing the Reliability Benefits of Grid-Forming Batteries" (ESIG, March 2023), https://www.esig.energy/wp-content/uploads/2023/03/ESIG-GFM-batteries-brief-2023.pdf.

[31] Michael Milligan, "Reply Comments of Michael Milligan, Ph.D.: Grid Reliability and Resiliency Pricing, Docket No. RM18-1-000," 2017, http://www.milligangridsolutions.com/Milligan-Comments-FERC%20from%20ferc%20web.pdf.

[32] See generally Yinong Sun, "Research Priorities and Opportunities in United States Competitive Wholesale Electricity Markets" (Grid Modernization Laboratory Consortium, May 2021), https://www.nrel.gov/docs/fy21osti/77521.pdf.

[33] U.S. Energy Information Administration, Form 930 Data, via "Real-Time Operating Grid - U.S. Energy Information Administration (EIA)," accessed July 31, 2023, https://www.eia.gov/electricity/gridmonitor/index.php.

[34] "Electric Power Monthly - U.S. Energy Information Administration (EIA), Table 6.2.C.," accessed July 31, 2023, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_c.

may protest section 111(d) restrictions on coal plant emissions on reliability grounds, the industry's emerging consensus is that unabated coal is not necessary for reliable operation and resource adequacy.

Many of these plans were developed before the IRA's passage, which significantly enhanced federal incentives for clean energy production and CCS. Even without this proposed rule, we expect to see many more utilities develop plans to phase out unabated coal use by 2035 or sooner as those utilities update their resource plans to account for the suite of federal clean energy tax credits now available.

Twenty-five large utilities plan to end coal use by 2035 or earlier

Based on data on utility integrated resource plans (IRPs) collected by EQ Research and EIA data, we identified 25 large utilities that currently own or are contracted to take power from an estimated 40 GW of coal capacity, and which have plans to be coal-free by 2035 or sooner. In many cases, these plans are articulated in an IRP, a detailed utility-led study of electricity system reliability and future resource needs. IRPs consider requirements of environmental policy, electricity system resource costs and characteristics, and use modeling to determine the optimal balance of meeting electricity system requirements while minimizing the costs and risks to consumers.

Table 2 shows the list of large utilities that have plans to be coal-free by 2035 or sooner, the amount of coal capacity to be retired between 2023 and 2035, and each utility's plans for resource additions to meet system needs.

The plans represented in this table account for 740 million MWh per year of electricity demand (representing roughly 19 percent of U.S. electricity demand) and cover 40 GW of coal capacity (accounting for 21 percent of currently operating coal capacity in the U.S.).The plans surveyed here include 56 GW of solar additions, 15 GW of wind additions, 10 GW of storage additions, and 32 GW of gas capacity additions between 2023 and the coal phase-out date for each utility.

Table 2. Utilities with Coal Phase-Out Plans

					Portfolio Changes from 2023 to Coal Phase-Out Date (MW)							
Name	Utility Type	Retail Cust.	Electricity Demand (MWh)	Coal Phase-Out Date	Coal Rets.	Other Rets.	New Solar	New Wind	New Energy Storage	New DSM	New Gas	Other New
Tennessee Valley Authority	Federal Power Agency	10,000,000	152,906,037	2035	(7,900)	-	5,145	-	-	-	7,700	-
Florida Power and Light	Investor Owned	5,691,891	123,054,514	2029	(717)	(219)	13,261	-	100	167	271	-
Georgia Power Co	Investor Owned	2,657,949	82,944,041	2035	(3,848)	(1,506)	8,130	-	1,270	-	9,166	1,158
DTE Electric Company	Investor Owned	2,244,945	41,481,966	2035	(4,336)	(70)	6,000	2,400	1,560	-	2,216	-
Northern States Power Co (Xcel)	Investor Owned	1,787,958	39,923,938	2030	(2,295)	(1,456)	2,570	1,350	200	341	-	1,441
Consumers Energy Co	Investor Owned	1,870,123	32,251,402	2025	(1,908)	-	1,300	-	-	94	2,177	-
Arizona Public Service Co	Investor Owned	1,317,266	29,228,236	2031	(1,357)	-	3,100	1,033	3,109	187	1,859	-
Public Service Co of Colorado	Investor Owned	1,535,755	28,932,674	2031	(2,549)	-	2,758	2,300	400	78	505	1,276
City of San Antonio (CPS Energy)	Municipal	885,307	22,605,374	2028	(1,345)	(1,279)	1,080	300	750	-	2,569	102
Entergy Arkansas LLC	Investor Owned	727,743	22,281,971	2030	(1,194)	(522)	2,730	1,500	-	-	-	-
LADWP	Municipal	1,465,281	20,800,118	2025	(1,200)	(9)	98	141	152	150	553	92
Public Service Co of Oklahoma	Investor Owned	568,226	18,205,777	2026	(465)	(79)	1,350	2,800	-	-	-	-
Indiana Michigan Power Co	Investor Owned	604,489	17,207,677	2028	(2,123)	-	1,300	800	315	4	750	-

Northern Indiana Public Service Co	Investor Owned	483,297	15,607,008	2028	(1,191)	(155)	1,665	204	270	-	353	-
Indianapolis Power & Light Co	Investor Owned	514,140	12,972,559	2025	(1,487)	(36)	478	-	298	111	1,052	-
Entergy Mississippi LLC	Investor Owned	458,987	12,744,935	2030	(413)	(1,266)	450	250	-	-	-	-
Wisconsin Power & Light Co	Investor Owned	487,076	11,185,445	2026	(1,003)	-	764	-	-	-	-	-
Great River Energy	G&T Co-op	725,000	10,650,069	2031	(1,050)	-	200	1,171	202	-	-	-
Mississippi Power Co	Investor Owned	190,660	9,254,379	2027	(502)	(474)	-	-	-	-	-	-
Public Service Co of NM	Investor Owned	540,035	9,163,032	2031	(200)	(409)	240	-	438	109	480	-
Hoosier Energy Rural Electricity Cooperative, Inc	G&T Co-op	710,000	7,321,571	2023	(990)	-	500	300	-	-	300	-
Orlando Utilities Commission	Municipal	261,047	6,823,920	2027	(663)	-	894	-	350	-	823	-
Colorado Springs Utilities	Municipal	244,132	4,785,436	2030	(415)	-	175	200	167	90	180	20
Vectren/ Centerpoint	Investor Owned	149,852	4,644,664	2027	(995)	-	756	200	-	-	730	-
Platte River Power Authority	Municipal Power Agency	169,856	3,133,575	2030	(352)	-	300	250	300	-	104	-
Total		36,291,015	740,110,318		(40,498)	(7,479)	56,494	15,199	9,879	1,331	31,788	4,089

Notes and Sources:

Resource additions and retirements based on data from EQ Research, IRP As a Service, as of June 2023. Additional data was collected on Tennessee Valley Authority, Great River Energy, Orlando Utilities Commission, Colorado Springs Utilities, Vectren/Centerpoint, and Platte River Power Authority from utility websites and IRPs.

Coal phase-out dates are based on the expected retirement year of each utility's last remaining coal plant, based on data from EQ Research, utility IRPs, and EIA Form 860.

Retail customers and retail electricity demand from EIA Form 861 and estimated based on utility websites and EQ Research data for Tennessee Valley Authority, Hoosier REC, Great River Energy, Platte River Power Authority based on retail customers and demand of member distribution co-operatives and municipal utilities.

Case Studies

Each of the utilities listed above has developed a plan to end the use of coal-fired electricity generation. We have selected four utilities below to explain these plans and coal retirement decisions in more detail. We chose utilities that represent a broad range of ownership types and operating structures (integrated investor-owned utilities, generation and transmission cooperatives, municipal utilities), as well as utilities that currently or have recently relied heavily on coal-fired generation as a large share of the electricity generation mix. In addition, according to data from the Smart Electric Power Alliance, three of the utilities (NIPSCO, Xcel Energy, and CPS Energy) have utility-level or parent-company goals to achieve net-zero carbon dioxide emissions by 2050 or sooner. The fourth utility (Great River Energy) is subject to Minnesota state policy that requires cooperative utilities to generate 100 percent of electricity from emissions-free sources by 2040.[35]

Many of the plans described below were completed before the passage of the IRA, which significantly increased the amount of federal support for clean energy and substantially shifted the economics of clean energy relative to coal.

Xcel Energy

Xcel Energy operates vertically integrated investor-owned utilities in Colorado and the Upper Midwest. In Colorado, Xcel's operating company Public Service Company of Colorado (PSCo) serves 1.5 million customers and supplies 29 million MWh of electricity per year. In August 2022, the Colorado Public Utilities Commission approved a settlement agreement that would retire or fully convert to gas PSCo's remaining coal units by the beginning of 2031.[36] Before the agreement was reached, the utility had been proposing to build over 2.7 GW of distributed and utility-scale solar, 400 MW of storage, 2.3 GW of wind, and 1.3 GW of firm dispatchable capacity by 2031,[37] although these amounts are likely to change to account for accelerated coal retirement.

Northern State Power Company (NSPC), Xcel Energy's upper Midwest utility, serves 1.8 million customers and supplies 40 million MWh of electricity demand per year. In 2020, the utility expected to meet 16 percent of electricity demand from coal generation, 28 percent from gas, 26 percent from nuclear power, and 30 percent from renewable energy resources.[38] Because NSPC has produced more recent and detailed plans to transition from coal by 2030, we will focus on that plan for the purpose of these comments.

NSPC filed an updated IRP in June 2020 that outlined a transition from coal-fired power with the retirement of the utility's entire coal fleet by 2030. The utility currently operates four coal units, totaling 2.7 GW in generating capacity: the 511 MW Allen King power plant, and 2.2 GW of capacity across three units at the Sherburne County power plant (Sherco). The IRP maintained the utility's currently scheduled retirements of Sherco units 2 and 1 in 2023 and 2026, respectively, and proposed retiring the King power plant in 2028. In addition, the plan proposed retiring Sherco unit 3 by the end of 2029.[39]

[35] Smart Electric Power Alliance, "Utility Carbon-Reduction Tracker™," accessed July 31, 2023, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.
[36] Colorado Public Service Commission, "Phase I Decision," (Decision No. C22-0459, Proceeding No. 21A-0141E), August 3, 2022.
[37] Xcel Energy, "2021 Electric Resource Plan and Clean Energy Plan," (Proceeding No. 21A-0141E), March 31, 2021.
[38] Xcel Energy, "Upper Midwest Integrated Resource Plan, Supplement, 2020-2034," (Docket No. E002/RP-19-368, 2020). https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/Upper-Midwest-Energy-Plan-Supplement-063020.PDF.
[39] Xcel Energy, "Upper Midwest Integrated Resource Plan, Supplement," 63.

NSPC initially proposed to build, by 2030, 3,500 MW of new solar, 835 MW of new combined cycle gas, and 374 MW of peaking gas resource, along with investing in energy efficiency and demand response.[40] In response to stakeholder concerns about climate impacts of new gas, the utility filed an alternate plan in June 2021 that removed the combined cycle gas proposal and proposed to meet system needs with 2,570 MW of solar, 1,350 MW of wind, 200 MW of energy storage, 340 MW of energy efficiency and demand response, and 1,400 MW of unspecified firm capacity resources by 2030.[41] By 2030, NSPC's resource mix would consist of no coal, 19 percent natural gas, 26 percent nuclear, 39 percent wind, 13 percent solar, and 3 percent other carbon-free resources, achieving 81 percent carbon-emissions-free generation by 2030.[42]

As part of this resource planning process, NSPC undertook extensive reliability modeling. The utility used modeling software that represents every hour of the year in chronological order to capture the timing and profile of the utility's capacity and energy needs in each projected year. In addition, the utility modeled extreme weather conditions based on the January 2019 Polar Vortex event, during which the upper Midwest region saw elevated electricity demand coinciding with multiple days of low wind output. Finally, the utility evaluated its ability to provide black start services in the unlikely case it would need to re-energize the grid after a widespread outage. Across these reliability needs, NSPC concluded that its plan to retire coal and significantly increase wind and solar would adequately meet the utility's needs.[43]

Northern Indiana Public Service Company

Northern Indiana Public Service Company (NIPSCO) is a vertically integrated investor-owned utility that serves roughly 480,000 customers and supplies more than 15 million MWh of electricity per year. Today, NIPSCO relies heavily on coal. The company expected to meet annual energy needs in 2021 with 58 percent coal generation, 25 percent natural gas, and 15 percent wind.[44]

In 2018, NIPSCO undertook a comprehensive IRP process, beginning with an all-source request for proposals that provided cost and performance data, which NIPSCO then used in its system-wide modeling.[45] That IRP resulted in NIPSCO selecting a portfolio that retired the remainder of its coal fleet by 2028, with the bulk of replacement resources from new wind and solar, driven by competitive costs discovered through NIPSCO's all-source resource solicitation process. NIPSCO refined this analysis in 2021 with updated cost and performance assumptions as well as a more detailed reliability assessment, selecting a portfolio that replaced the utility's Michigan City and RM Schahfer coal units (totaling 2.2 GW), with 2.7 GW of solar, 1 GW of wind, 353 MW of peaking gas and uprates of existing gas units, and 300 MW of energy storage through 2030, as well as additional investment in energy efficiency and demand response.[46] NIPSCO's plan includes short-term reliance on wholesale capacity purchases from the

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[40] Xcel Energy, "Upper Midwest Integrated Resource Plan, Supplement," 63.
[41] Xcel Energy, "Upper Midwest Integrated Resource Plan 2020-2034, Reply Comments" (Docket No. E002/RP-19-368), 113, https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={70F0437A-0000-CF1C-96D6-E7E22CE60B9C}&documentTitle=20216-175386-01.
[42] Xcel Energy, "Upper Midwest Integrated Resource Plan," 5.
[43] Xcel Energy, "Upper Midwest Integrated Resource Plan," 30-53.
[44] Northern Indiana Public Service Company LLC, "2021 Integrated Resource Plan," November 15, 2021, 14, https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf?sfvrsn=6.
[45] Northern Indiana Public Service Company LLC, "2018 Integrated Resource Plan," October 31, 2018, 5, https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf.
[46] Northern Indiana Public Service Company LLC, "2021 Integrated Resource Plan."

Midcontinent Independent System Operator (MISO) market through 2024, as new renewables and storage resources come online.[47]

NIPSCO's 2021 IRP undertook a detailed reliability assessment that evaluated portfolios' ability to provide a range of reliability and system services, including black start, energy adequacy, ability to provide ramping, frequency response and operational flexibility services, and more. NIPSCO's IRP found that the preferred portfolio performed well on all the reliability and system services measures evaluated.[48]

NIPSCO's coal replacement planning illustrates the value of detailed system planning informed by market-based resource cost and performance data, and it supports the EPA's baseline scenario, which sees nearly all coal retiring by 2035 based on economics alone. The new federal incentives for clean energy under the IRA significantly expand opportunities for cost-effective coal retirement and clean energy replacement.

Great River Energy

Great River Energy (GRE) is a generation and transmission (G&T) cooperative that provides wholesale electricity to member cooperatives across Minnesota. GRE does not sell power directly to retail customers; rather, it sells power to member distribution cooperatives under long-term contracts. GRE's members serve more than 700,000 customers, and GRE sold more than 10 million MWh in 2022.

G&T cooperatives like GRE are unique in their exposure to coal-fired electricity generation and the financial impacts of a transition from coal. G&T cooperatives own roughly 12 percent of operating coal capacity, but generate only 4 percent U.S. net electricity generation from resources they own.[49] In addition, many G&Ts face significant financial barriers to early retirement and replacement of coal-fired power plants because of high existing debt loads and limited ability to raise new sources of capital for new investment.[50] The U.S. Department of Agriculture's New ERA Program, authorized in the IRA, provides significant new resources to support rural electric cooperatives' transition from coal to clean energy.[51] This will enable many rural electric cooperatives to undertake the type of transition from coal that GRE is planning.

GRE has long relied on coal as a large part of its generation portfolio. In 2021, GRE generated 57 percent of its energy mix from coal, 25 percent from wind, 3 percent from natural gas, and 15 percent from market purchases without a specified source.[52] The majority of this coal generation came from GRE's 1.2 GW Coal Creek Station in North Dakota, which delivers energy to GRE in Minnesota over a dedicated high-voltage direct current (HVDC) transmission line. After initially announcing plans to retire the plant in 2020, citing the plant's high operating cost relative to market prices,[53] GRE changed course and sold the plant. In 2022, GRE finalized the sale of Coal Creek Station to Rainbow Energy, while entering a contract to purchase power from the plant; the purchases step down

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[47] Northern Indiana Public Service Company LLC, "2021 Integrated Resource Plan," 259.

[48] Northern Indiana Public Service Company LLC, 2021 Integrated Resource Plan," Appendix E.

[49] Calculated based on data from U.S. Energy Information Administration, Form 861, 2021. Excludes power purchased by G&T cooperatives to serve member demand.

[50] RMI, "Maximizing the Financial Opportunity of the New ERA Program," June 12, 2023, https://rmi.org/wp-content/uploads/dlm_uploads/2023/06/Maximizing-the-Financial-Opportunity-of-the-New-ERA-Program.pdf.

[51] U.S. Department of Agriculture, "Empowering Rural America New ERA Program," accessed July 2023, https://www.rd.usda.gov/programs-services/electric-programs/empowering-rural-america-new-era-program.

[52] Great River Energy, "2023-2037 Integrated Resource Plan," Docket No. ET-2/RP-22-75, March 31, 2023, 8, https://greatriverenergy.com/wp-content/uploads/2023/03/2023-IRP-FINAL.pdf.

[53] Presentation by Jon Brekke to Minnesota Legislative Energy Commission, November 2020, https://www.lec.mn.gov/2020/Legislative%20Energy%20Commission%20JBrekke%20111320_1.pdf.

over time, completely phasing out by 2031.[54] In addition, GRE operates the 99 MW Spiritwood Station, a coal-fired combined heat and power plant. The plant has been retrofitted to be able to burn natural gas exclusively, and GRE has announced plans to convert the plant to gas.[55]

Between 2023 and 2031, when GRE's contract with Rainbow Energy phases out, GRE plans to build 200 MW of solar, 1,171 MW of new wind, and 201.5 MW of energy storage capacity (including a small demonstration of long-duration iron-air battery technology). These capacity additions are complemented with expected demand-side energy efficiency and demand response, plus an increase in the amount of energy that member cooperatives can self-supply with local renewable energy resources from 5 to 10 percent.[56] While GRE's IRP does not specify the extent to which system needs are met with future MISO market purchases, GRE's central assumption limits market purchases to 25 percent of annual demand.

GRE's reliability needs were modeled on a seasonal basis, based on seasonal planning reserve margins that varied from 7.4 percent in summer to 25.5 percent in winter, applied to seasonal peak demand. The contribution of various resources to meeting these reliability requirements was based on MISO's Effective Load Carrying Capability estimates. By operating as part of MISO, one of the country's largest integrated wholesale electricity market operators, GRE can tap into a wide array of regional resource adequacy resources while benefitting from regional diversity in electricity demand and generator production profiles.

CPS Energy (City of San Antonio, TX)

CPS Energy is a municipal utility in San Antonio, Texas, serving 885,000 customers and supplying more than 22 million MWh of demand annually, making it the largest municipal utility in the U.S. by total electricity demand.[57]

In 2023, CPS expects to meet approximately 30 percent of electricity demand from coal, 30 percent from gas, 25 percent from nuclear power, and 15 percent from renewable energy resources.[58] Since the 2018 closure of the 871 MW Deely Power Plant, CPS's coal generation has come entirely from the 1.3 GW JK Spruce Power Plant.

In February 2023, CPS's board approved a resource plan that would end the utility's reliance on coal by retiring JK Spruce Unit 1 in 2028, and converting JK Spruce Unit 2 to run solely on natural gas after 2027. In addition, CPS plans to retire 1.7 GW of aging gas-fired capacity by 2030. CPS's plan would meet growing demand and replace the utility's last remaining coal units and retiring gas with a mix of renewable energy, energy storage, and new natural gas generation. By 2030, the utility would add roughly 3 GW of gas capacity (including the 785 MW conversion of Spruce 2), 500 MW of wind capacity, 1,180 MW of solar, and 1,060 MW of energy storage.[59] The resulting portfolio would meet CPS's 2030 energy needs with roughly 21 percent nuclear, 23 percent wind and solar, and 56 percent natural gas generation.[60]

In developing its resource plan, CPS undertook detailed reliability and risk assessment analysis. Across the portfolios CPS developed and considered in this plan, it accounted for a 13.75 percent capacity reserve margin above CPS's peak demand, while developing capacity accreditation for each resource that accounts for that resource's

[54] Great River Energy, "2023-2037 Integrated Resource Plan," 13.
[55] Presentation by Brekke.
[56] Great River Energy, "2023-2037 Integrated Resource Plan," 11.
[57] U.S. Energy Information Agency, Form 861, 2021.
[58] CPS Energy, "2022 Power Generation Plan Initial Reference Case Results Discussion, Rate Advisory Committee Meeting – October 20, 2022," 45. Figures estimated from graphic.
[59] CPS Energy, "2022 Power Generation Plan Initial Reference Case Results Discussion," 16.
[60] CPS Energy, "2022 Power Generation Plan Initial Reference Case Results Discussion," 45.

contribution to peak net demand (total demand net of renewable energy).[61] In addition, CPS undertook a scenario analysis simulating extreme winter weather and corresponding market conditions based on the impacts of Winter Storm Uri in February 2021, as well as extreme summer weather conditions based on the July-August 2021 Texas heat wave. This scenario analysis allowed CPS to assess the performance of portfolios on cost, reliability metrics, and exposure to market volatility under extreme conditions.[62]

CPS's board ultimately determined that a portfolio that retires JK Spruce and meets future needs with a mix of renewable energy, energy storage, and gas generation resources strikes the right balance as to cost, environmental performance, reliability, and risk.

Key takeaways

Many utilities are planning a transition from coal-fired electricity by 2035 or sooner. This transition is driven in large part by the potential for cost savings as aging and higher-cost coal power plants become less competitive to continue operating as the cost of clean energy alternatives declines.[63] Utilities planning a transition from coal include a broad range of utilities, from some of the nation's largest investor-owned utilities to small utilities, municipal utilities, and rural electric cooperatives. These transitioning utilities plan to meet their system needs with a mix of new wind and solar resources, natural gas-fired generation, energy storage, and other technologies. Many of these plans were developed before the August 2022 passage of the IRA, which significantly increased and extended federal incentives for clean electricity. As more utilities update their plans to account for the IRA, we can expect more to set timelines and plans for coal phase-out.

Across the cases evaluated, utilities have demonstrated rigorous planning, drawing on rapidly evolving technology options and resource costs and employing modern electricity system modeling tools to select portfolios of resources that minimize costs and risks while meeting reliability and environmental performance goals. These plans are often the result of an iterative process with regulators and third-party stakeholders, providing a level of transparency and scrutiny to the planning process.

The growing list of utilities aligning with this coal retirement timeline based on market economics alone supports the EPA's projection that even without the proposed rule, nearly all coal will retire by 2035. Even before the IRA, utilities around the country were committing to end their use of coal-fired electricity by or before 2035, demonstrating the reliability, feasibility, and cost-effectiveness of a transition from coal to cleaner sources of electricity that will be supercharged by new federal incentives and continued technological progress. Transitioning from coal is even in utility shareholders and consumers' best interests – Morgan Stanley utility stock analysts indicated that utilities leading on the transition from fossil fuels, especially coal, have higher stock valuations than their peers.[64]

No doubt, the EPA was aware of these utility plans in considering the impacts of its proposed rule, and utilities that raise objections to the rule should take stock of their peers that are already planning to exceed the rule's

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[61] CPS Energy, "2022 Power Generation Plan Initial Reference Case Results Discussion," 18.

[62] CPS Energy, "2022 Power Generation Plan Results Discussion, Rate Advisory Committee Meeting – November 17, 2022," 15, https://www.cpsenergy.com/content/dam/corporate/en/Documents/RAC/November%20RAC%20Presentation%20-%20Final%20Updated%2011-16.pdf.

[63] See generally Michelle Solomon et al., *Coal Cost Crossover 3.0* (Energy Innovation, January 2023), https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.

[64] Energy Innovation: Policy and Technology, "Why The American Jobs Plan Would Benefit Coal-Heavy Utility Stocks," Forbes, accessed August 8, 2023, https://www.forbes.com/sites/energyinnovation/2021/07/12/why-the-american-jobs-plan-would-benefit-coal-heavy-utility-stocks/.

requirements. These utilities help demonstrate that many industry actors already understand what the studies examined in Sections 1 and 2 show: electricity systems large and small can be resource adequate, affordable, and operationally reliable without coal-fired power by 2035 or sooner, even as the share of renewable energy grows.

In conclusion, Energy Innovation appreciates the opportunity to submit these comments and commends the EPA for its efforts to realize a cleaner electricity future by reducing CO_2 emissions from coal- and other fossil-fired power plants. Please feel free to contact me with any inquiries regarding these comments.

Sincerely,

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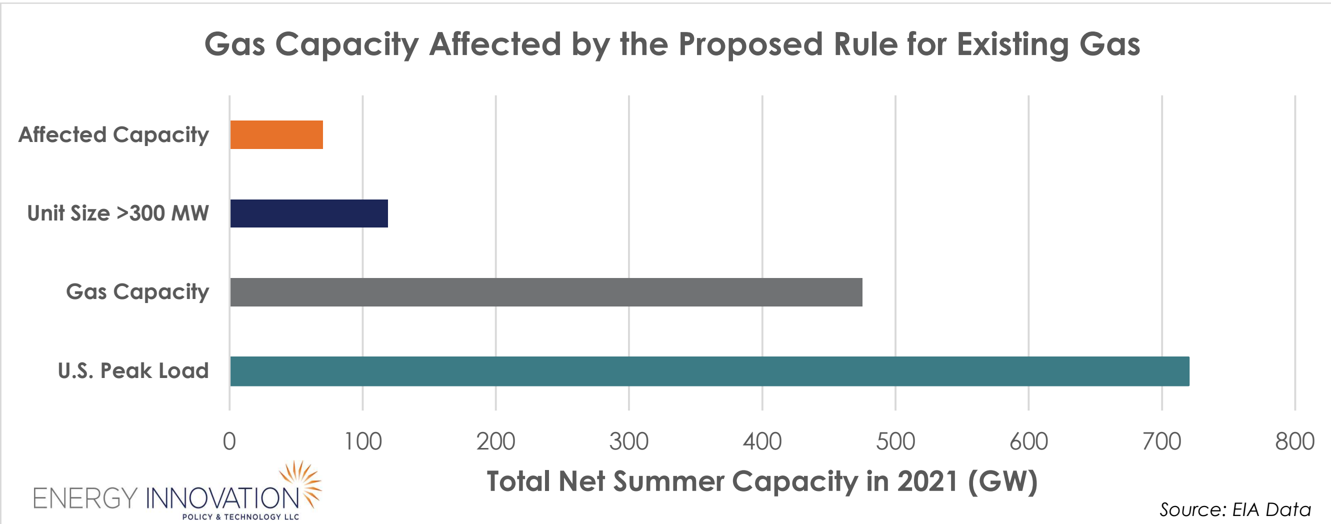
Appendix 1: Resource adequacy, essential reliability services unlikely to be undermined by limits on emissions from existing gas-fired power plants.

The arguments and studies identified in these comments also support the proposition that EPA's rules limiting the emissions from existing gas-fired power plants will likely not undermine reliability. The key to any change in the bulk electricity system resource mix is proper planning and regulation – maintaining reliability while reducing emissions in line with the EPA's proposed rule for existing coal or existing gas is technically feasible.

Today there is a total of 475 GW[65] of total gas capacity in the U.S. (excluding expected retirements through 2032), of which 411 GW is CT or CCGT technology, according to EIA data. Of the total fleet of 475 GW of natural gas power plants in operation today, we estimate using 2021 EIA data that 70 GW, representing 189 units, would meet the 300 MW unit size and 50 percent capacity factor threshold today – 15 percent of total gas capacity.



Whether these 70 GW or some other number would be subject to EPA regulation under the existing gas rule depends upon whether capacity factors for these units remain fixed over 10 years. A high-level look at fleet-wide utilization indicates there is ample room for flexible compliance. Gas capacity factors today average roughly 38 percent, well below the threshold of 50 percent that the EPA proposes for gas plants that would trigger emissions reductions in 2035 for units with CCS or 2032 for units that blend hydrogen. While EPA proposes technologies that represent the best system of emission reduction for covered plants, in many cases it will be a cheaper or simpler option for utilities and power plant operators to comply with this regulation by running higher capacity factor units less and lower capacity factor units more, thus avoiding regulation under the proposed existing gas rule. As the grid evolves to accommodate more low-cost renewable energy through 2032, it is reasonable to expect that gas capacity factors could even fall on average as they did in the NREL-sponsored examination of IRA impacts.[66] This average capacity factor may fall further if new natural gas capacity is added to the grid as many utilities plan to do.[67]

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[65] These numbers all use Summer Nameplate Capacity, which is reflective of reliability contributions. The operating gas fleet would be 573 GW if using nameplate capacity.

[66] Daniel Steinberg et al., "Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System" (National Renewable Energy Laboratory, March 15, 2023), at pp. 9-10.

[67] See Section 3, above, where the utilities examined planned to add more than 30 GW of new natural gas as part of their transition away from coal.

Resource Adequacy

In aggregate, the six studies examined in the comments above each rely on existing gas operating at a lower capacity factor compared to today to meet demand and resource adequacy requirements in the study period. The six studies examine power systems where clean energy shares grow faster than EPA anticipates, with each including scenarios that reach at least 78 percent carbon-free generation by 2035. In other words, all six studies illustrate how grids can remain resource adequate even when gas provides 22% or less of total generation in a coal-free system. Increased renewable deployment contemplated in these studies would displace both existing coal generation and displace natural gas generation, as wind and solar fuels are zero marginal cost. Yet each model was able to maintain resource adequacy through the study period despite differences in time and geography.

For example, the 2035 Report 2.0[68] maintains resource adequacy in a 90 percent carbon-free generation mix without building new gas power plants and reducing the utilization of existing gas significantly. Average gas fleet capacity factors in the 2035 Report 2.0 would fall from 38 percent today to roughly 16 percent in a 90 percent clean electricity future. Regulations with 50 percent capacity factor minimums to trigger emissions reductions therefore would have likely miniscule, if any, effect on resource adequacy in a high renewables grid.

In another example, the GridLab, Telos, Energy Innovation study[69] of California's resource adequacy with a higher share of renewables resulted in a similar dynamic of decreasing utilization of existing gas. In that study, the fleetwide capacity factor for all types of natural gas fired power plants is approximately 10 percent in an 85 percent clean grid in 2030, with combined cycle (CC) units at 15 percent, and steam turbine (ST) and combustion turbine (CT) generators at less than 2 percent each. Few units in this context would be affected by the proposed rule for existing gas units, and if any were, there would be ample headroom to shift gas generation between low- and high-capacity factor units to handle any concerns associated with emissions reduction requirements undermining system reliability.

Essential Reliability Services

The proposed rule on existing gas does not fundamentally alter the ERS available to the grid. As previously stated, the rule either limits the amount of energy that an existing gas plant provides over the course of a year to 50 percent of its potential output or it requires emissions reducing technology including hydrogen blending and CCS. Either option would allow the gas plants to continue providing ERS. In addition, the proposed rule's regulations on new gas plants allow for new efficient peakers to be built, along with higher capacity factor gas units that comply with proposed emission limits. Even as ERS from gas won't be undermined, the capability of IBRs like wind, solar, and storage to supply ERS services has been demonstrated, and has been shown to surpass the performance of traditional resources like existing coal and gas, as summarized in Section 2 of the comments above.

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[68] Amol Phadke et al., "2035 The Report: Transportation - Plummeting Costs and Dramatic Improvements in Batteries Can Accelerate Our Clean Transportation Future."
[69] Stenclik, Welch, and Sreedharan, "Reliably Reaching California's Clean Electricity Targets: Stress Testing Accelerated 2030 Clean Portfolios." At p. 56.